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THE DEREGULATION OF ELECTRIC UTILITIES IN CALIFORNIA AND ITS EFFECT ON NAVY INSTALLATIONS

by

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June 1997

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Deregulation will dissolve the monopoly of the electricity industry by allowing customers to choose who will supply their electricity. Competition will emerge in the generation market, where transactions between consumers and suppliers will be free and open. Under regulation, most customers do not have a choice in their electricity supplier. Their supplier is usually determined by their geographic location.

This thesis researches the differences between the regulated and deregulated rate structures and provides a cost comparison for a Navy organization classified as a large commercial/industrial user of electricity.

There are many aspects of deregulation that are not yet determined, but the initial comparison indicates deregulation may save Navy installations money. If deregulation progresses as planned, additional future saving may occur.

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June 1997

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I. INTRODUCTION

A. BACKGROUND

Navy installations spend a significant amount of their Operations and Maintenance, Navy (O&M,N) budgets on utilities and, in particular, electricity. For example, the Naval Postgraduate School (NPS) may spend less than seven percent of its non-labor O&M,N budget on electricity, but that percentage actually equates to over $1 million a year. Therefore, any reduction in electricity consumption may produce significant cost savings. As a result, commands adopt energy conscious programs to reduce electricity consumption and, ultimately, the costs. Unfortunately, these programs can only reduce wasteful electricity consumption. Additionally, no matter how energy conscious a command may be, there are still environmental factors that affect consumption and over which the command has no control. Therefore, commands can only reduce their consumption and costs by a certain amount.

Another component which affects the amount installations pay for electricity is the rate schedule. In California, approximately 80 percent of all electricity service is provided by three investor owned utilities (IOUs), Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric [Ref. 1:p. 2]. These companies are given exclusive rights to provide electricity to specific geographic areas. Since these rights create monopolistic markets, the state invokes regulation as a surrogate for competition. Regulation controls all aspects of the IOUs' operations, which includes setting the rate schedules. Therefore, the rates customers pay for electricity depend on their geographic location, which dictates their electricity supplier and ultimately their rate schedule.

California legislators believe that the electricity rates paid in California are too high and have responded with Assembly Bill 1890. This bill, which was signed into law on September 23, 1996, will deregulate the electricity industry by breaking up the three IOUs and allow other electricity suppliers to compete for retail customers. It is believed that deregulation will decrease electricity rates because competition will determine the price, not regulation. If Navy installations could reduce their electricity rates, the savings would be genuine.

This thesis researched how electricity rates are determined under regulation, how deregulation will affect those rates, and whether Navy installations in California will realize lower electricity costs under deregulation.

B. RESEARCH QUESTIONS

The primary research question is: Will Navy installations, which receive electricity from one of California's three IOUs, save money as a result of deregulation?

Secondary research question are:

1. What laws and regulations govern California's electricity industry?
2. How does California plan to deregulate its electricity industry?
3. How will the electricity rate structure for Navy installations change under deregulation?

C. METHODOLOGY

This research was conducted in three parts. First, a review was made of the regulated rate setting procedures for the IOUs. This was accomplished through a rate case for Southern California Edison decided by the California Public Utilities Commission (CPUC). Second, information on how California plans to deregulate the electricity industry was reviewed. Deregulation information was obtained through various sources, such as Assembly Bill 1890, the 1994 Electricity Report prepared by the California Energy Commission, and an Internet site managed by the CPUC. The CPUC site contains a wealth of information about the operations and proceedings of the CPUC, as well as a dedicated section for deregulation. Third, a cost comparison between a regulated rate schedule and deregulation was conducted for a Navy organization in order to determine what type of cost savings, if any, may be realized.

D. THESIS STRUCTURE

This thesis is divided into five chapters. Chapter I is the thesis background, methodology, and structure. Chapter II concentrates on the regulated electricity industry. It provides the reader a brief background on why the industry is regulated and how rates are determined by the regulators.

Chapter III contains the theory and method by which California will deregulate the industry. It discusses what aspects of the industry will change and how the rates will be determined. Chapter IV compares the cost of electricity for the Naval Postgraduate School's Main Station, which is classified as a large commercial/industrial user of electricity. This chapter applies a baseline forecast to the applicable rate schedule and to the projected cost of electricity after deregulation. Chapter V contains the conclusions and recommendations from the study.

II. CALIFORNIA'S REGULATED ELECTRICITY INDUSTRY

A. INTRODUCTION

At the turn of the century, vast applications for electricity were just starting to be realized. People then believed that, because of its natural characteristics, the emerging industry could best serve the public as a monopoly. For example, multiple transmission lines throughout neighborhoods, each provided by different companies competing for the same business, were thought to be inefficient. Additionally, multiple transmission lines running throughout every neighborhood would have been unsightly. [Ref. 2:p. 1]

The characteristics of the electric industry that naturally lend themselves to monopolistic behavior also provide economic benefits. Single transmission lines are economically more efficient for two reasons. First, single transmission lines reduce the amount of electricity lost during transmission. Second, resources are not wasted on duplicate lines. [Ref. 3]

However, the absence of competition, or existence of a monopoly, can also have detrimental effects on a free market economy. Society is essentially a captured market because the good or service can not be received by any other means. A monopoly is free to set any price and is often not responsive to customer needs. This may lead to a breakdown in areas such as safety, quality of service, and, most importantly, inefficient use of valuable resources.

B. UTILITY REGULATION

In an attempt to protect the captured market from the monopolists' rule, the government imposes regulation. Regulation is designed to simulate the characteristics of a competitive market by regulating all aspects of the industry, from rates to the quality of service provided. Today, the electric industry is regulated nationally by the Federal Energy Regulatory Commission (FERC), and in California by the California Public Utilities Commission (CPUC).

1. Federal Regulation

The Federal Energy Regulatory Commission is a division within the Department of Energy. The commission was established in 1977 by the Department of Energy Organization Act. Its charter is to regulate the transmission of natural gas and oil and the transmission and wholesale market for electricity in interstate commerce; to inspect and license private, municipal and state hydroelectric projects; and to oversee related environmental matters. The Commission ensures that wholesale electric rates, service standards, and electricity transmission through interstate commerce are conducted in accordance with federal laws. In summary, FERC regulates interstate utility transactions and claims no jurisdiction over electric rate setting within the states. [Ref. 4:p. 1]

2. State Regulation

The California Public Utilities Commission was originally established as the Railroad Commission in 1911. In 1946, its name was changed to the CPUC and it was empowered to regulate the utilities and transportation services within the state. The CPUC's decision-making body is its Board of Directors. The board includes five members, each appointed by the governor and approved by the senate. Each member serves a six year term. [Ref. 5:p. 1]

The CPUC's job is to protect consumers from electric and transportation monopolies by regulating safety, standards of service, and rates. The Commission must also consider the financial status of the investor-owned utilities. It must allow utility companies to recover their operating costs and capital costs and still provide a reasonable rate of return for their shareholders. Therefore, the Commission must balance the public interest and the utilities' interests when setting electric rates. [Ref. 5:p. 1]

C. RATEMAKING

The California Public Utilities Commission spends a great deal of time and resources reviewing utilities' applications for rate increases. These applications presumably are not attempts by the utilities to increase profits, but substantiated requests to adjust rates to meet their revenue requirement. During the review process, several contrasting ratemaking policies may be employed, depending on one's outlook. The method CPUC uses is a marginal cost-based ratemaking policy. [Ref. 6:p. 3] This policy is designed to "achieve rates which reflect the costs that the customer imposes on the system." [Ref. 6:p. 20]

The theory behind marginal cost is that economic efficiency will occur if goods are priced at the point where the cost to produce one additional unit is equal to the benefit received from consuming that unit. Therefore, the CPUC's objective is to set the price of electricity at an optimal point where the quantity of electricity consumed is equal to the amount produced and the marginal cost of the last unit produced equals the marginal value of that unit to consumers. If this objective is met, then the proper amount of resources will be allocated to the electric industry. [Ref. 6: Attach. 3,pp. 1-3]

The marginal cost ratemaking policy has been used by the CPUC since 1981. This policy distributes electric costs in the most equitable manner, while providing customers with information about their electricity consumption. The marginal-cost ratemaking process is divided into two parts. They are:

1. Establish the revenue requirement.

2. Allocate the established revenue requirement. [Ref. 6:p. 13]

The following subsections will discuss each part of this process, as illustrated in Figure 1.

1. Establish the Revenue Requirement

The revenue requirement is the total of all current costs to the utility, which include: operation and maintenance, fuel, taxes, depreciation, interest payments, and an allowance for return on equity. These costs, or expenses, are referred to as embedded costs and equal the amount authorized by the CPUC to be recovered through electricity rates. It should be noted that embedded costs include capital investment costs. [Ref. 6:pp. 16]

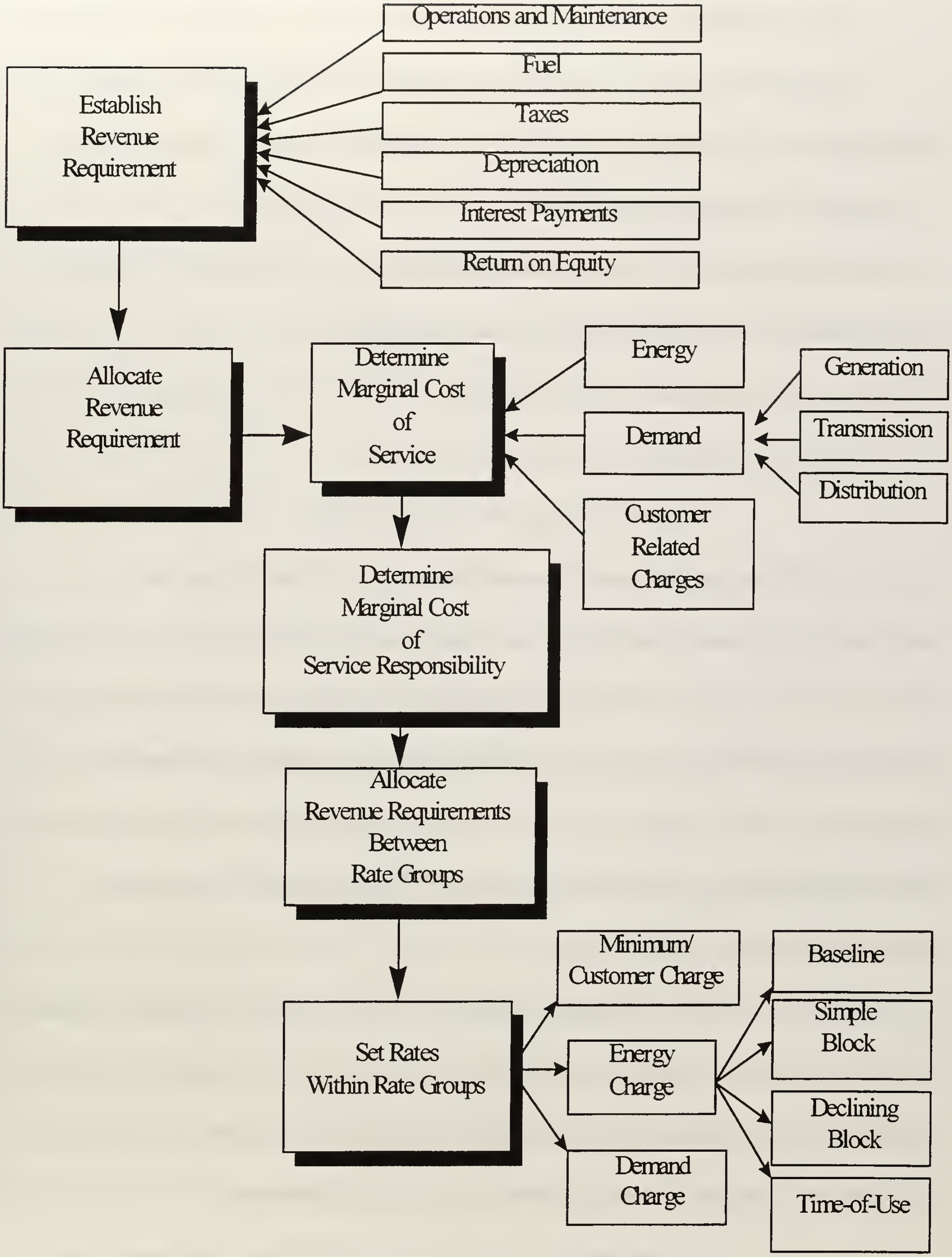

Figure 1. Marginal Cost of Service Ratemaking.

2. Allocate the Revenue Requirement

The allocation process is a four step procedure which determines how the authorized revenue requirement will be spread between rate groups. The four steps are:

a. Determine marginal cost of service.

b. Determine marginal cost of service responsibility.

c. Allocate the revenue requirement between rate groups.

d. Set rates within rate groups. [Ref. 6:p. 16]

The following explains each step in more detail:

a. Determine Marginal Cost of Service.

The marginal cost of service is determined by the marginal costs of its three principal components, energy, demand, and customer-related costs.

(1) Energy. The marginal cost of energy is defined as the additional cost incurred to produce one additional unit of electricity, measured as a kilowatt hour (kWh). The cost of energy is variable, depending on the time of day and season. Marginal energy costs include the cost of fuel plus variable operation and maintenance expenses. [Ref. 6:p. 24]

(2) Demand. Demand is the level of capacity needed to meet the workload. Because electricity is difficult and expensive to store, electricity must be instantaneously generated in order to meet the current demand on the system. If demand were to exceed system capacity, blackouts and/or greyouts could ensue.

The marginal cost of demand is the additional cost incurred to produce one additional unit of demand measured as a kilowatt (kW). The marginal cost of demand is determined by the marginal costs of generation, transmission, and distribution.

(a) Generation.

Generation is the process that provides electricity to the system. The process is accomplished by various methods such as hydroelectric, nuclear, and fossil-fired. The CPUC defines the marginal cost of generation as "… the change in total costs of providing dependable capability to deliver energy from the generating system." [Ref. 6:pp. 51-52]

(b) Transmission.

Transmission is the process of transporting high-voltage electricity from the generation facility to the distribution point. California's transmission lines are complex networks interconnected throughout the western United States. These networks allow interconnection between generating plants and provide backup electricity in times of emergencies. [Ref. 2:p. 11]

The marginal cost of transmission was not originally calculated as part of the system marginal costs. In 1982, however, the California Public Utilities Commission decided that transmission costs should be added to system marginal costs. As kW demand increases, transmission lines reach their capacity, increasing the probability of a system shortage. Therefore, customers should bear the costs they impose on the limits of the transmission lines by the relationship between new plant investment and transmission load growth. [Ref. 6:p. 56] (c) Distribution.

From the transmission lines, electricity is transferred to the distribution system via substations. Substations are used to reduce the high-voltage electricity from the transmission lines to lower voltages used by the distribution system. A distribution system consists of primary and secondary lines which distribute electricity to distribution transformers. The distribution transformers reduce the voltages to usable levels for end users. Marginal distribution costs are determined in the same manner as transmission marginal costs.

(3) Customer-Related Costs. The final marginal cost is customer-related costs. These costs measure the change in total costs required to provide access to the system for new customers and the costs to maintain current customers. Examples of customer costs include customer equipment, customer service, and accounting expense. [Ref. 6:p. 24] Customer-related costs are estimated by a "new customer only" (NCO) method. This method assigns the lump sum cost for new hook-ups to each group based on the number of new customers and estimated replacements. Current costs are estimated based on the total number of customers in the rate group. The marginal customer related costs are the sum of the NCO cost and current costs for each group. [Ref. 6:pp. 62-69]

b. Determine Marginal Cost of Service Responsibility

The marginal cost of service responsibility assigns each rate group responsibility for the marginal costs incurred by the utility. This is referred to as the

Marginal Cost Revenue Responsibility (MCRR). The MCRR is a percent which represents a rate group's contribution towards total marginal costs. [Ref. 6:pp. 23-24]

c. Allocate Revenue Requirement Between Rate Groups

The allocation of revenue requirement distributes the revenue requirement between the rate groups. This is accomplished by a method called equal percent marginal cost (EPMC). The EPMC allocates the revenue requirement based on each rate group's MCRR. For example, if a rate group's MCRR is 35 percent then the revenue requirement for that group will be calculated based on 35 percent. [Ref. 6:p. 6]

d. Set Rates Within Rate Groups

Utility customers are divided into service categories called rate groups. Rate groups consist of customers who receive similar service based on their energy needs and usage. Each rate group is further divided into specific rate schedules. These schedules will define, at a minimum, the applicability, territory, rates, and special conditions that may apply to the type of service. The rate schedules are the vehicle used to distribute the rate group's assigned revenue requirement.

Each IOU has unique rate schedules which apply to its customers. This is because each utility's customer base and authorized revenue requirements are different. Regardless of the differences between the rate schedules, the type of charges are the same. The primary charges that comprise a customer's bill are:

(1) Minimum or basic charge.

(2) Customer Charge.

(3) Demand Charge.

(4) Energy Charge.

These charges are not inclusive for all schedules but are applied as the CPUC distributes the revenue requirement within the rate group. Each charge is discussed in further detail in the following subsections:

(1) Minimum or Basic Charge. The minimum or basic charge recovers a minimum amount of revenue for customer related costs, such as metering and billing. This charge normally applies to domestic service.

(2) Customer Charge. The customer charge applies to all customers except domestic and is also used to recover customer related charges. This charge is normally a fixed cost.

(3) Demand Charge. The demand charge, which recovers the component costs of demand as discussed above, is based upon coincidental and non-coincidental customer demand. Coincidental demand is the customer's demand which contributes to generation peak demand. The coincidental demand charge is usually "time of use" (TOU) related and increases from off-peak, to partial-peak, and peak, respectively. [Ref. 6: p. 57]

Non-coincidental demand is the customer's maximum demand placed on the local distribution system. The non-coincidental demand, or facilities-related charge, is TOU independent and is a flat fee dependent on the maximum demand during the period. The customer's demand charge will be the total of the coincidental and facilities-related charges. [Ref. 6:p. 57]

(4) Energy Charge. Energy charges apply to all customers and are designed to recover the cost of fuel, operations and maintenance, and the remainder of the revenue requirement not yet recovered by customer charges and demand charges. The charges are structured to recover the energy costs within each rate group in a manner that best represents the energy usage characteristics of the group's customers. The CPUC employs different allocation methods to meet its goals. Four methods are predominant in the rate schedules. They are: (a) baseline, (b) flat rate, (c) declining block, and (d) time-of-use.

(a) Baseline Rates.

The baseline method applies to domestic users and provides a minimum quantity of electricity at a low rate. The schedule is structured into two tiers. The first tier provides the minimum quantity of energy at the low rate, while the second tier sets a higher rate for all energy usage above the minimum. The monthly energy charge for this schedule is the total of tier one and tier two costs. The baseline rate and quantity will vary according to utility, climate, and season and is employed throughout California.

(b) Simple Block.

The simple block or flat rate method charges one rate for all energy use. This method has restricted applications based on customer demand and monthly energy use. For example, San Diego Gas and Electric (SDGE) flat rate schedule applies only to customers whose monthly demand is less than 20 kW and monthly consumption less than 12,000 kWh. Energy cost under this schedule is the single set rate times the consumption. [Ref. 7]

(c) Declining Block.

The declining block method is a consumption based rate structure. This method divides energy consumption into blocks and charges a corresponding rate for consumption within that block. Because the cost to produce energy decreases with increased volume, the block rates decline as consumption increases. This method usually applies to customers with monthly demand greater than 20 kW but less than 500 kW.

(d) Time-of-Use.

The last method of rate allocation is the time-of-use (TOU) schedule. TOU schedules charge energy consumption based on the time of day in which it is used. The most common TOU schedules divide the day into peak, partial peak, and off peak periods. These periods will vary depending on time of day, region, climate, and season. The peak period is when energy use is the highest; therefore it equates to the highest rate. The off peak period is when energy use is the lowest and corresponds to the lowest rate. The primary applicants for TOU schedules are large power users with monthly demand greater than 500 kW. Table 1 is an example of the TOU time periods used by San Diego Gas and Electric.

Period	Summer May 1 - Sept. 30	Winter All other
Peak	11 a.m. - 6 p.m. Weekdays	5 p.m. - 8 p.m. Weekdays
Partial Peak	6.a.m. - 11a.m. Weekdays 6 p.m. - 10 p.m. Weekdays	6 a.m. - 5 p.m. Weekdays 8 p.m. - 10 p.m. Weekdays
Off Peak	10 p.m. - 6 a.m. Weekdays Plus Weekends & Holidays	10 p.m. - 6 a.m. Weekdays Plus Weekends & Holidays

Table 1. San Diego Gas and Electric Time Periods. (SDGE Schedule A6-TOU)

D. CONCLUSION

In conclusion, the ratemaking process determines the amount of revenue the utility is allowed to generate based on its current costs plus an amount to ensure a reasonable return on equity. The process then determines the marginal costs and assigns the marginal cost revenue responsibility to each rate group. The revenue requirement is then allocated to the rate groups based on the equal percent marginal cost method, as previously discussed.

III. CALIFORNIA'S DEREGULATION OF THE ELECTRICITY INDUSTRY

A. INTRODUCTION

On September 23, 1996, the governor of California signed Assembly Bill 1890 (AB 1890). This legislation will deregulate nearly 80 percent of electricity service provided by California's three investor-owned utilities (IOUs), specifically Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E). [Ref. 1:p. 1]

This bill was created in response to the high electricity rates paid in California and the changing composition of the electricity industry. California lawmakers and customers were frustrated with the electricity rates paid in California compared to the rest of the country. The average California electric bill is lower than the national average. However, California electricity rates are 40 percent higher. [Ref. 8:pp. 1-4] This is due in part to the stringent energy conservation measures and energy efficiency programs adopted by California. These programs reduce energy consumption but result in higher rates because the fixed costs of the IOUs must be spread over the lower energy consumption. [Ref. 2:p. 2]

Legislation, such as the Energy Policy Act of 1992 (EPAct), has shifted the paradigm of the electric industry. The EPAct provided wholesale electricity generators nondiscriminatory access to the transmission grid at reasonable rates. This effort increased competition and lowered rates within the wholesale generation market created by nonutility generators. [Ref. 2:p. 2]

The California Energy Commission (CEC) believes lower electricity rates are essential to the well being of the state. The CEC states,

> Energy is essential to California's economy. The state's long-term economic growth relies on, among other factors, an adequate and stable supply of energy in all major forms: transportation fuels, electricity and natural gas. It is time for reform. California needs stable energy prices, as low as can be achieved consistent with concern for the environmental impacts of energy use, as part of the foundation for a sound economy, new industries, jobs and export opportunities for California's businesses. [Ref. 9:p. 6]

Today, regulation controls every aspect of the electricity industry. The issues regarding who will provide service to whom, how much customers will pay for electricity, and even where and how many power plants will be built are all decided by regulation. The theory behind the deregulation of electricity is to allow the natural forces of supply and demand to control the electric industry. State authorities are optimistic that these forces will increase economic efficiency and ultimately reduce rates. [Ref. 2:p. 1]

B. DEREGULATION

The deregulation of electricity will permit electricity suppliers to compete for retail customers. Under regulation, the investor-owned utilities (IOUs) provide electricity to customers according to the customers' geographic location. Each IOU receives exclusive rights to serve specific locations. However, in return for these rights each IOU must provide service to all customers within that area. Under this situation, if the customer chooses to receive electricity, it must be from the utility with the rights to serve that location. Deregulation will dissolve these exclusive rights and allow virtually all utilities access to all regions. The customers will be able to choose their electricity supplier.

It is essential to the success of deregulation that competitive markets exist where transactions are free and open between suppliers and consumers. This will likely prove to be the biggest challenge for deregulation. California's IOUs have evolved, with the help of regulation, into vertically-integrated corporations. This means generation, transmission, distribution, and customer services are all provided by a single utility company. [Ref. 2:pp. 1-9]

The vertical-integration of the utilities provides substantial market power, which makes it difficult for smaller companies to compete. For a truly competitive market to exist, the vertical-integration of these utilities must be dissolved. This will be accomplished by "unbundling" each component of electricity service. [Ref. 2:p. 1]

C. ASSEMBLY BILL 1890

Assembly Bill 1890 (AB 1890) states that three situations must occur in order for a competitive generation market to exist. They are:

1. Separate monopoly utility transmission functions from competitive generation functions, by developing independent, third-party control of transmission access and pricing.

2. Permit all customers to choose among competing electric power suppliers.

3. Provide customers and suppliers with open, nondiscriminatory, and comparable access to transmission and distribution services. [Ref. 10:Section 330.k]

These situations depend on separating generation, transmission, and distribution from the vertically-integrated IOUs. The legislation accomplishes this separation by establishing two government agencies, an Independent System Operator (ISO) and Power Exchange (PX).

1. Independent System Operator

The Independent System Operator (ISO) will function as the central coordinator for electricity transmission. It will coordinate the operations of the electricity network to ensure that safety and reliability standards are maintained. This will be accomplished by the IOUs transferring control of their transmission facilities to the ISO. The ISO will operate as an independent entity controlled by regulation. [Ref. 10:Section 330.m]

In addition to network coordination, the ISO will act as a dispatch service for electricity. This service will maintain system reliability by purchasing electricity to meet any differences between the system's supply and demand. The dispatch service will decide where to purchase electricity, based on the lowest bid from the generation market. [Ref. 6:p. 15]

The establishment of the ISO is designed to break the vertical-integration of the IOUs by separating generation from transmission. This will allow all generation suppliers open access to the network, thereby providing the necessary connection between generation and retail customers without IOU intervention.

2. Power Exchange

Assembly Bill 1890 establishes a competitive auction service to dispatch electricity generation, called the Power Exchange (PX). The PX will serve as a mediator for generators with excess capacity and retail suppliers. The PX will accomplish this through an open bid auction where generators bid excess capacity through the PX. Retail suppliers will also bid through the PX, but they will do so with demand requirements.

The PX will match the demand of the retail suppliers with the lowest generation bids. [Ref. 11:Section III.B.2]

Introducing the ISO will separate the vertically-integrated IOUs, but the California Public Utility Commission (CPUC) is also concerned about the horizontal market power the IOUs will have in the generation market. The CPUC states,

> There is a need to ensure that no participant in these new market institutions has the ability to exercise significant market power so that operation of the new market institutions would be distorted. [Ref. 12:Section II.D]

The CPUC will implement two policies to prevent the IOUs from exercising generation market power. First, the IOUs will be required to divest themselves of 50 percent of their fossil-fired generating facilities. Second, a mandatory buy-sell policy will require the IOUs to bid all their generation through the PX. In return, the IOUs will buy electricity back from the PX to meet their customers' demand. [Ref. 12:Section II.B - II.D.1]

D. ELECTRICITY RATES UNDER DEREGULATION

Deregulation will promote competition within the electricity industry by unbundling the components of electricity service. Competition will emerge primarily in the generation market, which is where customers will choose who will supply their electricity. Transmission and distribution are critical to system reliability, and therefore will remain regulated. Because each component of electricity service may be provided by different companies, electric bills may reflect the separate costs of generation, transmission, distribution, and customer-related costs. Additionally, AB 1890 has authorized a Competitive Transition Charge (CTC) to be added to all customers' bills during a specified transition period.

1. Generation

Customers may choose between various electricity suppliers such as the local utility, the PX, and retail suppliers. Once an electricity supplier is chosen, the customers will enter into a bilateral contract with that supplier. Three contract options the customer may choose are:

a. Retain local utility service.

b. Stabilize price through financial hedging.

c. Direct access. [Ref. 11:Section I.B.1]

The theory behind each contract option will be discussed in further detail below:

a. Retain Local Utility Service

Under this contract, customers will retain all services from their local utility company. The local utility will be responsible for providing all services from generation to distribution and will charge the customer for the bundle of services. Residential and small commercial customers will have an additional choice between block rates or time-of-use (TOU) billing. TOU rates were not available for these customers under regulation.

The cost of electricity will be determined by the market rate. If a customer is not satisfied with the local utility rate, the customer may choose a new supplier. [Ref. 11:Section I.B.1]

b. Stabilize Price Through Financial Hedging.

Customers who are concerned about price stability within the competitive electricity market may enter into a hedging contract with a third party. Customers who enter into this type of contract will continue to receive bills from their local utility company. However, periodically bills will be totaled and compared to the hedged contract price. The third party will pay the customer for any amount greater than the hedged price. Conversely, the customer will pay the third party for any amount less than the contract price. Under this contract, the customer will be able to predict electricity costs independent of market fluctuations. [Ref. 11:Section I.B.2]

c. Direct Access

Direct access will provide retail customers the opportunity to negotiate the price of electricity directly from suppliers. The retail customer and the supplier will decide on the terms and conditions of a direct access contract without government intervention. Direct access will open the generation market to competition. Utilities will compete for retail business against other utilities and nonutility generators. As such, the generation market will be open to anyone willing to compete and not just electricity producers. [Ref. 11:Section I.B.3]

Direct access contracts must also include the local utility, which must deliver the electricity from the supplier to the customer. The CPUC believes that, as long as mutually satisfactory contract arrangements are made among the customer, supplier, and local utility, there is no need for government involvement. [Ref. 11:Section I.B.3]

2. Transmission

As stated above, the Independent System Operator (ISO) will control the transmission facilities to allow non-discriminatory access to the transmission grid. The ISO will determine the cost for using the transmission network based on the marginal cost of generation at different locations.

The following is an example of how the marginal costs of different locations will operate. This example is taken from the California Energy Commission, *1994 Energy Report*:

> Suppose the price of generation at location A is 3 cents per kilowatt hour and the price at location B is 5 cents per kilowatt hour. If there are no transmission constraints and enough generation at A, a customer at either A or B should pay only 3 cents for generation. But suppose there was insufficient transmission between A and B, so that not all the 3-cent generation consumers wanted from A could get to B. In that case, the price of generation for consumer at A would still be 3 cents; but the price for a customer located at B would be 5 cents.
>
> If a consumer at B sought to purchase power from a 3-cent generator at A, it could sign a contract to pay 3 cents for the generation, but it would not be able to receive all of that power; that is, some portion of the generator's 3-cent power could not be physically transmitted to B because of network constraints. To enable the consumer at B to get its remaining power, generation at B would have to be used and its price would be 5 cents, raising the spot price for power delivered at B to 5 cents.
>
> Continuing the example, if power had been offered to the ISO's dispatch service at these different prices, the ISO would have been offered power at A at 3 cents and power at B at 5 cents. Given the network constraint, some of the 3 cent power would not have been taken; instead, the ISO would have dispatched the remaining power at B, paying 5 cents. The consumer at B would have paid 5 cents for all its power, even though part of the power would have come from A at 3 cents. [Ref. 2:pp. 17]

The difference, at location B, between the 5-cent price paid and 3-cent price will equal the price for transmission, i.e., 2-cents. The ISO will set the price of transmission between locations based on the price of electricity sold through the exchange at those different locations. The transmission prices will apply to all users of the transmission system. [Ref. 11:Section I.C.3]

The ISO will create congestion contracts for customers entering long-term generation agreements which require using the transmission system. These contracts will give the customer the right to transport all their contracted electricity over the transmission lines. Under this circumstance, the customer will not be subject to the market congestion of the transmission network. [Ref. 11:Section I.C.3]

3. Distribution

The investor-owned utilities will retain the ownership and control of their distribution facilities, which will remain regulated in order to maintain system reliability. This will ensure that non-discriminatory service is provided to all customers.

The cost of distribution services will no longer be determined by the marginal cost of service but by a method called Performance Based Ratemaking (PBR). Regulators believe that the marginal cost of service has become too difficult and complex to maintain in the new competitive electricity market. [Ref. 11:Section III.E] PBR is an incentive type of ratemaking which establishes benchmarks to measure the utility's performance. Performance above the benchmark would receive financial rewards, performance below the benchmark would result in a financial penalties. Similar to cost of service, each utility will be measured against benchmarks unique to its distribution area. [Ref. 11:Section III.E.1]

To date, the benchmarks and the performance measurements for PBR have not yet been established. Until then, customers will pay the distribution rate established in the applicable June 10, 1996 rate schedule.

4. Customer Related Charges (Revenue Cycle Services)

The California Public Utility Commission has decided to unbundle revenue cycle services from the distribution services to help promote competition in the new electricity market. This decision will provide energy suppliers with three billing options:

a. Consolidated energy supplier bill.

b. Consolidated distribution company billing

c. Dual billing.

Each option is discussed below:

a. Consolidated Energy Supplier Billing.

Revenue cycle services are provided by the energy supplier under this option. Distribution services provided by the local distribution utility to the customer will be billed to the energy supplier. The energy supplier will present the customer with a consolidated bill for all electricity service.

b. Consolidated Distribution Company Billing.

Under this billing option, the local distribution company will provide revenue cycle services. The energy supplier will bill the distribution company for the customer's energy use; the distribution company will then present the customer with a consolidated bill.

c. ***Dual Billing.***

This billing option separates energy service from distribution services. Therefore, both the energy supplier and distribution company will provide revenue cycle services and bill the customer separately. [Ref. 13:The PG&E Model]

The unbundling of revenue cycle services is only applicable to customers who receive electricity from suppliers other than their local utility company.

5. Competitive Transition Charge

Assembly Bill 1890 authorizes the collection of a Competitive Transition Charge (CTC) to recover the loss from the uneconomical assets of the IOUs. Legislators feel the IOUs should not be completely responsible for the cost of uneconomical assets acquired under regulation. An uneconomical asset is an asset whose book value exceeds its market value. The CTC covers regulatory assets, existing power purchase obligations, and uneconomical utility generating assets. (Ref. 11:Section I.A]

All customer groups will be allocated a portion of the CTC based on the equal percent of marginal cost (EPMC) method. Once allocated, the transition cost will be collected as a surcharge based on a percentage of the customer's bill. [Ref. 11:Section V] The CTC will be collected during a transition period that will begin January 1, 1998 and not extend beyond December 31, 2001, with a few exceptions. [Ref. 10:Section 367.a - 367.e] It should be noted that customers who contract electricity from suppliers other than their local IOU, must still pay the CTC. [Ref. 10:Section 370]

E. CONCLUSION

In conclusion, electricity suppliers will compete for retail business, which should drive electricity rates below those set by regulation. Retail customers will have to decide who will provide their electricity. The decision may be as simple as staying with the local utility company or as complex as monitoring the market to find the best rate among competing suppliers.

The transmission of electricity will maintain the structure of a monopoly, run by an Independent System Operator, to ensure system safety and reliability. The cost of transmission will depend on where electricity is procured and the amount of network congestion between the supplier and customer.

The local utility will maintain control of distribution facilities and remain regulated to maintain system reliability and access. The cost of distribution will eventually be determined using an incentive ratemaking method, called Performance Based Ratemaking.

Revenue cycle services will be provided by either the supplier, the distribution utility, or both. The customer will be indifferent to who provides the revenue cycle services because the cost is usually negligible in relation to the rest of the bill. The provider will likely be determined by the electricity supplier based on the economic consequences of the service.

Finally, during a four year transition period, customers will be charged a competitive transition fee to recover the uneconomical assets acquired by the IOUs as a result of regulation. The CTC will appear as a surcharge to all customers' bills.

However, legislators are committed to ensuring that customers will not experience a rate increase as a result of the CTC if they purchase electricity at a rate equal to or less than that provided by the PX.

IV. COST ANALYSIS

A. INTRODUCTION

This chapter compares the cost of electricity for a Navy organization before and after deregulation. The comparison was conducted in four parts. First, electricity consumption and demand for the organization was forecast. Second, the forecast was applied to the organization's regulated rate schedule. Third, the forecast was also applied to the projected cost of the deregulated services. Finally, the costs were compared.

This analysis was conducted on the Naval Postgraduate School's Main Station, which is categorized as a large commercial/industrial electricity user with demand equal to or greater than 1000 kilowatts (kW). The main station receives electrical power from Pacific Gas and Electric (PG&E) and is charged according to PG&E's E-20 Rate Schedule.

B. ELECTRICITY FORECAST

The electricity forecast was conducted to provide an electricity consumption base with which to compare costs. The electricity forecast for the main station consists of a forecast for consumption and a forecast for demand. Data points were collected directly from PG&E electric bills for 24 months starting September 1994 and ending September 1996.(See Appendix A for data)

The billing cycles normally begin the last week of the previous billing month and end the third week of the current billing month. The cycles do not pose a problem except when the seasons change. This creates bills which include charges from both seasons.

Because the seasons' charges are distinguishable, they are separated and paired with similar seasons. For example, November's bill starts the winter season but includes summer charges for the last week of October. The charges for October are separated from the November bill and paired with the summer bills.

February 1995's data included total energy consumption only and did not provide the period's demand. Therefore, the demand was assumed to be the average of January 1995's and March 1995's demand.

1. Energy Consumption Forecast

The energy consumption forecast is conducted by forecasting the monthly energy consumption and then allocating the consumption between the PG&E time periods.

a. Monthly Energy Forecast

As Figure 2 indicates, the Main Station's monthly energy consumption does not indicate any significant difference between the summer and winter seasons but does indicate a slight decrease in trend. However, a closer look at the electric bills reveals the number of days per billing cycle varies from month to month. Therefore, an average daily consumption was calculated based on the monthly total divided by the number of days in the billing cycle. Figure 3 is the result of the calculation.

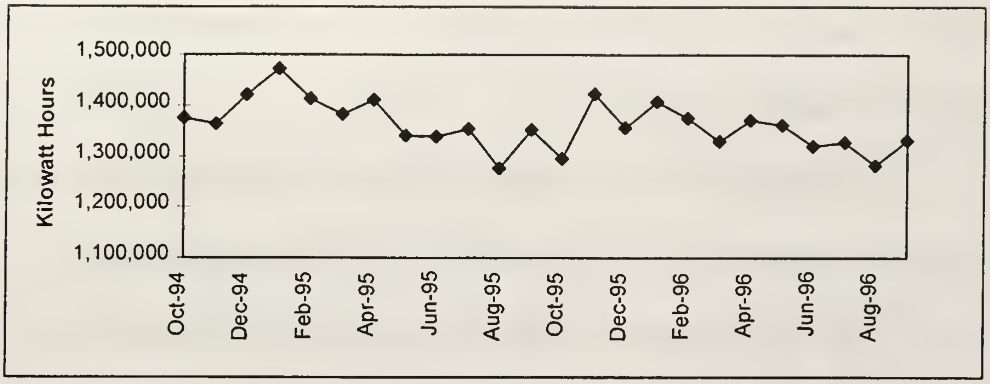

Figure 2. NPS Main Station Monthly Electricity Consumption.

Figure 3 confirms the decreasing trend indicated by Figure 2 but also indicates seasonality. The seasonality occurs every six months which correlates to the school's academic breaks. These breaks occur between June/July and December/January. The forecast was performed using the average daily consumption.

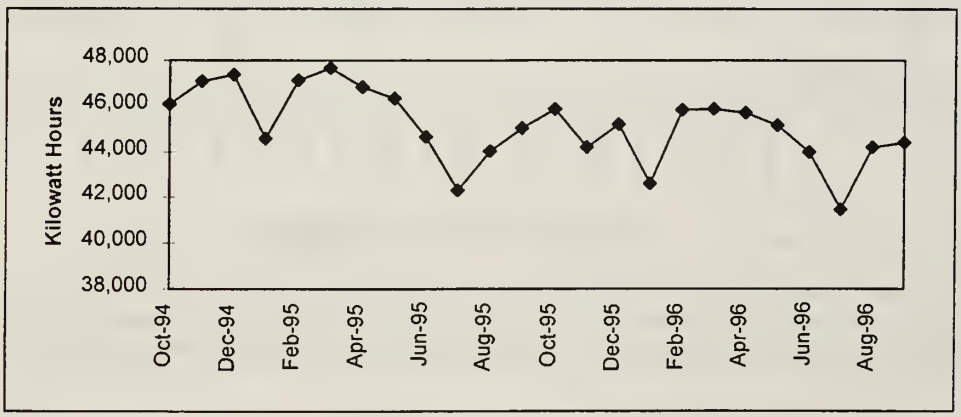

Figure 3. Average Daily Electricity Consumption.

Based on the trend and seasonality of the energy consumption data, the Classical Decomposition method of times series analysis is used. The Classical Decomposition method , in general, creates a seasonal index for each period by removing the seasonality from the data. It then calculates a regression equation based on the deseasonalized data, which is the trend. The forecast is then the product of the regression equation and the seasonal index. [Ref. 14]

This discussion will be limited to the results of the analysis and will not discuss the actual calculations. The calculations are contained in Appendix B.

Figure 4 validates the decomposition forecast by comparing it to the average daily consumption. This forecast is then used to calculate the monthly consumption by simply multiplying the forecast times the number of days per month. The calculations for the monthly forecast are contained in Appendix B.

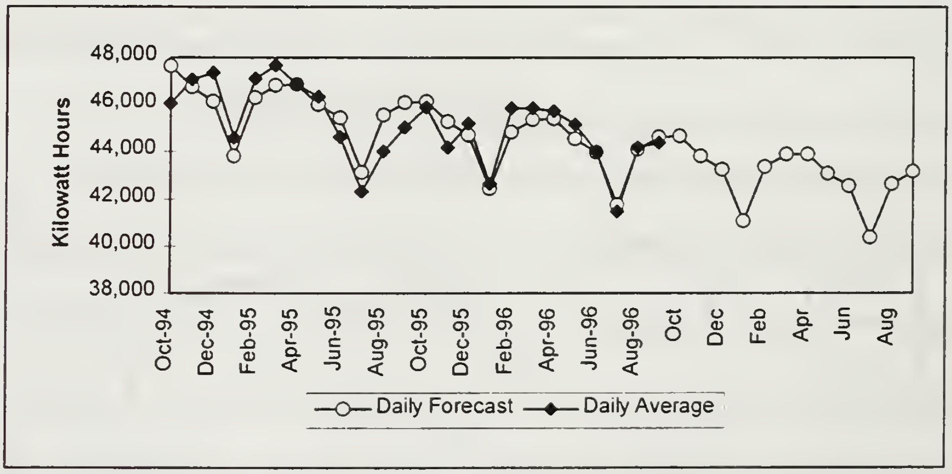

Figure 4. Daily Forecast vs. Average Daily Electricity Consumption.

b. Monthly Consumption Allocation

To accurately predict electricity costs, the monthly consumption is further divided between summer and winter, and further into time-of-use (TOU). Pacific Gas and Electric TOU rate schedules charge costs based on the season and also according to peak, partial peak, and off peak. Summer is defined as May 1st through October 31st and winter as November 1st through April 30th. Table 2 displays PG&E's periods as defined in their E-20 Rate Schedule.

Period	**Summer** (May 1st - Oct. 31st)	**Winter** (Nov. 1st - Apr. 30th)
Peak	1200 - 1800, Mon. - Fri. (except holidays)	Not Applicable
Partial Peak	0830 - 1200 and 1800 - 2130, Mon. - Fri. (except holidays)	0830 - 2130, Mon. - Fri. (except holidays)
Off Peak	2130 - 0830, Mon. - Fri. All day, Sat., Sun. and holidays	2130 - 0830, Mon. - Fri. All day, Sat., Sun. and holidays

Table 2. PG&E E-20 Rate Schedule Time Periods.

The first step in analyzing the period allocation was to calculate the proportion each period contributed toward total consumption. The percentages for peak, summer partial peak, summer off peak, winter partial peak, and winter off peak do not vary significantly between periods.(See Appendix C for calculations.) Therefore, the consumption allocation is calculated as the period average applied to the monthly forecast.

Table 3 shows the daily forecast, monthly forecast, and allocation of consumption based on the TOU percentages. These consumption forecasts are used for the analysis.

Month	Daily kWh	Monthly kWh	Peak	Partial Peak	Off Peak
October	44,654	1,384,274	308,278	329,457	746,539
November	43,808	1,314,240	N/A	596,928	717,312
December	43,258	1,340,998	N/A	609,081	731,917
January	41,064	1,272,984	N/A	578,189	694,795
February	43,375	1,214,500	N/A	551,626	662,874
March	43,891	1,360,621	N/A	617,994	742,627
April	43,914	1,317,420	N/A	598,372	719,048
May	42,080	1,335,480	297,411	317,844	720,224
June	42,538	1,276,140	284,196	303,721	688,222
July	40,378	1,251,718	278,758	297,909	675,052
August	42,649	1,322,119	294,436	314,664	713,019
September	43,154	1,294,620	288,312	308,120	698,189

Table 3. Forecast of Daily and Monthly Electricity Consumption.

2. Demand Forecast

Pacific Gas and Electric calculates the demand for each time period based on the maximum demand for that period. The maximum demand is determined as the highest average demand calculated over 30 minute intervals for the entire billing cycle. The demand charge is not based on a cumulative amount like energy, but a charge applied to the single highest average demand for the specific period.

A review of the demand data revealed that each season and period should be analyzed individually. The analysis for each period is presented below.

a. Summer Demand

The summer season, as defined in Table 2, is divided into three periods, peak, partial peak, and off peak. The demand from each period is graphed in Figure 5. All three periods show a trend decrease. However, there appears to be an anomaly in

September 1995's data. NPS personnel were questioned regarding possible causes for the anomaly but no insight was provided. Therefore, September 1995's data was removed prior to any analysis.

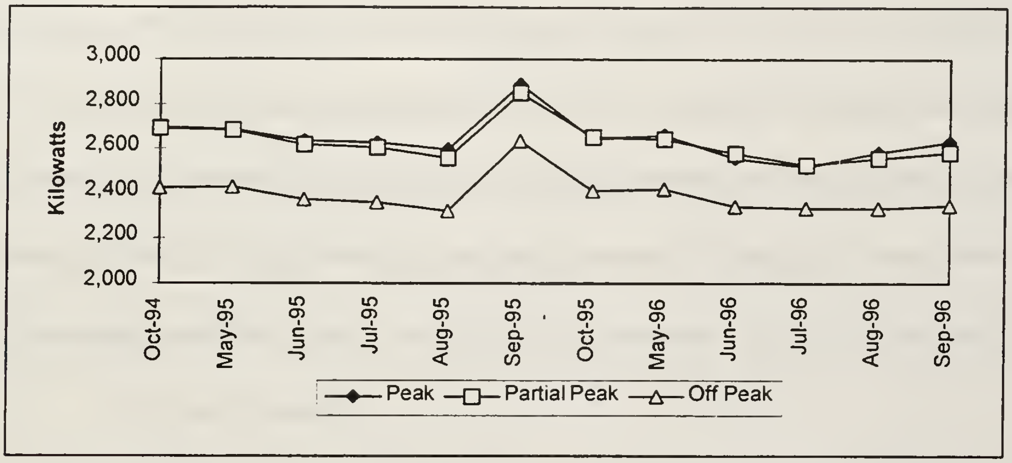

Figure 5. Summer Demand.

A demand forecast for each month was calculated as the average demand for the respective month. This method was used because the data was limited after the demand was divided between periods. Table 4 is the result of the demand forecast for the summer months. Since September 1995's data was removed, September 1996 demand was used as the forecast for September.

Summer	Peak (kW)	Partial peak (kW)	Off Peak
October	2,669	2,672	2,418
May	2,672	2,663	2,426
June	2,596	2,598	2,359
July	2,573	2,567	2,348
August	2,590	2,557	2,328
September	2,630	2,582	2,349

Table 4. Summer Demand Forecast.

b. Winter Demand

The demand periods change in the winter to partial peak and off peak only. Essentially, the summer peak period becomes partial peak. Otherwise, the time periods do not change. The analysis for winter demand was conducted in the same manner as the summer. As indicated in Figure 6, the winter data had an anomaly in the off peak demand for November 1994 which could not be explained. Therefore, this data point was removed from the analysis. The forecast for winter demand was calculated the same as the summer demand; the results appear in Table 5.(See Appendix D for calculations.)

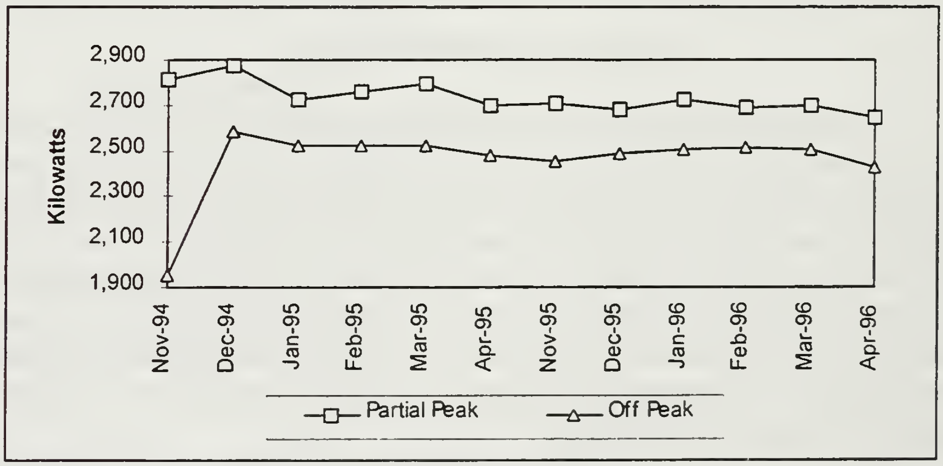

Figure 6. Winter Demand.

Winter	Partial Peak (kW)	Off Peak (kW)
November	2,760	2,452
December	2,780	2,536
January	2,723	2,518
February	2,724	2,520
March	2,747	2,515
April	2,675	2,454

Table 5. Winter Demand Forecast.

C. PACIFIC GAS AND ELECTRIC RATE SCHEDULE E-20

Pacific Gas and Electric's E-20 Rate Schedule applies to all PG&E customers with maximum demands of 1000 kilowatts (kW) or greater. The schedule further divides service into three categories, primary, secondary, and transmission. NPS's Main Station receives power under the primary schedule. Under the E-20 Rate Schedule, the customer pays a demand charge, energy charge, and customer charge. This cost estimate will include these costs only and will not include any adjustments.

1. Cost of Demand

The demand charge is the sum of each period's demand costs. Demand costs are calculated by multiplying each period's demand times the respective period's rate. The demand charge for the Main Station is predicted by multiplying the demand forecasts in Table 4 and Table 5 by the demand costs in Table 6.

Season	Demand Cost per kW		
	On Peak	Partial Peak	Off Peak
Summer	$11.80	$2.65	$2.55
Winter	$0.00	$2.65	$2.55

Table 6. PG&E Rate Schedule E-20P.

Table 7 lists both the demand costs by month and calculates the annual cost. The total demand cost of $345,238.35 is used below to calculate the total electricity cost.(See Appendix E for calculations.)

Month	Demand			Demand Total
	On Peak	Partial Peak	Off Peak	
October	$31,494.20	$7,080.80	$6,165.90	$44,740.90
November	$0.00	$7,314.00	$6,252.60	$13,566.60
December	$0.00	$7,367.00	$6,466.80	$13,833.80
January	$0.00	$7,215.95	$6,420.90	$13,636.85
February	$0.00	$7,218.60	$6,426.00	$13,644.60
March	$0.00	$7,279.55	$6,413.25	$13,692.80
April	$0.00	$7,088.75	$6,257.70	$13,346.45
May	$31,529.60	$7,056.95	$6,165.90	$44,752.45
June	$30,632.80	$6,884.70	$6,186.30	$43,703.80
July	$30,361.40	$6,802.55	$6,015.45	$43,179.40
August	$30,562.00	$6,776.05	$5,936.40	$43,274.45
September	$31,034.00	$6,842.30	$5,989.95	$43,866.25
Total	$185,614.00	$84,927.20	$74,697.15	**$345,238.35**

Table 7. Forecast Demand Costs.

2. Cost of Energy

The energy cost forecast is calculated in the same manner as the demand forecast. Table 8 lists the energy charges for PG&E's E-20P Rate Schedule. These values will be multiplied by the respective period's energy forecast from Table 3.

Season	Energy Cost per kWh		
	On Peak	Partial Peak	Off Peak
Summer	$0.06210	$0.04821	$0.04637
Winter	$0.00000	$0.05624	$0.04719

Table 8. PG&E Rate Schedule E-20P.

Table 9 lists the monthly and annual energy cost calculations. The annual cost of $796,810.32 is used to calculate the total electricity cost.

Month	Energy			Energy Total
	On Peak	Partial Peak	Off Peak	
October	$19,081.96	$15,883.12	$34,617.02	$69,582.10
November	$0.00	$33,571.23	$33,849.95	$67,421.18
December	$0.00	$34,254.72	$34,539.16	$68,793.88
January	$0.00	$32,517.35	$32,787.38	$65,304.73
February	$0.00	$31,023.45	$31,281.02	$62,304.47
March	$0.00	$34,755.98	$35,044.57	$69,800.55
April	$0.00	$33,652.44	$33,931.88	$67,584.32
May	$18,469.22	$15,323.26	$33,396.79	$67,189.27
June	$17,648.57	$14,642.39	$31,912.85	$64,203.81
July	$17,310.87	$14,362.19	$31,302.16	$62,975.22
August	$18,284.48	$15,169.95	$33,062.69	$66,517.12
September	$17,904.18	$14,854.47	$32,375.02	$65,133.67
Total	$108,699.28	$290,010.55	$398,100.49	**$796,810.32**

Table 9. Forecast Energy Costs.

3. Customer Charge

Rate Schedule E-20P charges $310.00 per meter per month for customer charges. The main station has one meter and therefore pays $310.00 per month or $3,720.00 annually.

4. Total Electricity Cost

As previously stated, the total electricity cost is the sum of the demand costs, energy costs, and customer charges. Based on the forecast data and above calculations , the cost of electricity under Rate Schedule E-20P is $1,145,768.67.(See Appendix E for calculations.)

D. UNBUNDLED COST OF ELECTRICITY

When the research for this analysis was conducted, many deregulation issues were unresolved, including the investor owned utilities (IOUs) unbundled cost of electricity . To progress toward rate unbundling, the California Public Utilities Commission (CPUC) requested that the IOUs file a rate unbundling application. This analysis used the application filed by Pacific Gas and Electric (PG&E) for three reasons:

1. The PG&E application unbundles electricity costs specifically for the E-20 Rate Schedule, and therefore provides the best comparison.

2. It is likely that NPS will initially retain electricity service from PG&E under deregulation.

3. The transmission and distribution costs are too uncertain to accurately predict electricity costs from a supplier other than PG&E.

Pacific Gas and Electric's electricity costs in the application are unbundled into six categories, they are Power Exchange price (generation), transmission, distribution, Competitive Transition Charge (CTC), nuclear decommissioning, and social/environmental.

The nuclear decommissioning cost is a mandatory (nonbypassable) charge related to the decommissioning of uneconomical nuclear generating facilities. Assembly Bill 1890 states this cost will be separate from the CTC and will fully recover the cost of these facilities. The social/environmental charge will provide funding for low income electricity users, energy efficiency and conservation programs, and public interest electricity research and development. The social/environmental cost is nonbypassable and will be included in the local distribution cost.

The unbundled cost estimate divides the calculation into two parts; the cost of service, which includes generation, transmission, distribution, and social/environmental charges, and the transition cost, which includes the CTC and nuclear decommissioning costs.

Pacific Gas and Electric's unbundled rates forecast listed in Table 10 are based on the class average and do not differentiate between peak, partial peak, and off peak periods. The cost estimate uses the 1998 rates and assumes theses rates represent the rates after deregulation. The unbundled costs are all charged according to consumption per kilowatt hour (kW).

Unbundled Costs (per kWh)	
PX Price (Generation)	$0.0240
Transmission (Trans.)	$0.0023
Distribution (Dist.)	$0.0096
Social/Environmental (S/E)	$0.0026
Competitive Transition Charge (CTC)	$0.0290
Nuclear Decommission (ND)	$0.0003
Total Rate	$0.0678

Table 10. PG&E E-20 Average Unbundled Rates Forecast. (Ref. 15:p. 2)

The estimated cost of service and transition cost are calculated by multiplying the monthly energy forecast from Table 3 by the unbundled rates forecast in Table 10. Table 11 provides the calculated cost of services and Table 12 shows the calculated transition cost. The unbundled cost of electricity from PG&E does not list any customer charges therefore, it is assumed customers who receive all electricity services from PG&E do not pay customer charges. The estimated unbundled cost of electricity is the sum of the cost of service and transition costs which equal $1,063,450.72.(See Appendix F for calculations.)

Month	Generation	Trans.	Dist.	S/E	Totals
October	$33,222.58	$3,183.83	$13,289.03	$3,599.11	$53,294.55
November	$31,541.76	$3,022.75	$12,616.70	$3,417.02	$50,598.23
December	$32,183.95	$3,084.30	$12,873.58	$3,486.59	$51,628.42
January	$30,551.62	$2,927.86	$12,220.65	$3,309.76	$49,009.89
February	$29,148.00	$2,793.35	$11,659.20	$3,157.70	$46,758.25
March	$32,654.90	$3,129.43	$13,061.96	$3,537.61	$52,383.90
April	$31,618.08	$3,030.07	$12,647.23	$3,425.29	$50,720.67
May	$32,051.52	$3,071.60	$12,820.61	$3,472.25	$51,415.98
June	$30,627.36	$2,935.12	$12,250.94	$3,317.96	$49,131.38
July	$30,041.23	$2,878.95	$12,016.49	$3,254.47	$48,191.14
August	$31,730.86	$3,040.87	$12,692.34	$3,437.51	$50,901.58
September	$31,070.88	$2,977.63	$12,428.35	$3,366.01	$49,842.87
Totals	$376,442.74	$36,075.76	$150,577.08	$40,781.28	**$603,876.86**

Table 11. Cost Estimate for Unbundled Cost of Service.

Month	CTC	ND	Total
October	$40,143.95	$415.28	$40,559.23
November	$38,112.96	$394.27	$38,507.23
December	$38,888.94	$402.30	$39,291.24
January	$36,916.54	$381.90	$37,298.44
February	$35,220.50	$364.35	$35,584.85
March	$39,458.01	$408.19	$39,866.20
April	$38,205.18	$395.23	$38,600.41
May	$38,728.92	$400.64	$39,129.56
June	$37,008.06	$382.84	$37,390.90
July	$36,299.82	$375.52	$36,675.34
August	$38,341.45	$396.64	$38,738.09
September	$37,543.98	$388.39	$37,932.37
Total	$454,868.31	$4705.55	**$459,573.86**

Table 12. Cost Estimate for Unbundled Transition Cost.

E. COST OF ELECTRICITY COMPARISON

This section compares the regulated and deregulated cost of electricity calculated above. The generation costs compare the E-20P energy charges and the Power Exchange price. The transmission and distribution costs compare the E-20P demand charge and the unbundled transmission, distribution, and social/environmental costs. The CTC includes both the transition charge and nuclear decommissioning.

The unbundled cost of electricity is 7.18 percent, or $82,317.95, cheaper than the regulated rates as illustrated in Table 13. More significantly, the unbundled cost of generation is $420,367.58 less than the regulated price; transmission and distribution are also cheaper under deregulation by $117,804.23. These savings are largely offset by the Competitive Transition Charge. This charge costs $459,573.86 and applies only to unbundled electricity.

Cost	E-20P	PG&E E-20 Unbundled Rates	Savings Under Deregulation
Generation	$796,810.32	$376,442.74	$420,367.58
Transmission & Distribution	$345,238.35	$227,434.12	$117,804.23
CTC	$0.00	$459,573.84	-$459,573.86
Customer Charge	$3,720.00	$0.00	$3,720.00
Total	$1,145,768.67	$1,063,450.72	**$82,317.95**

Table 13. Electricity Cost Comparison.

V. CONCLUSIONS AND RECOMMENDATIONS

A. CONCLUSIONS

The cost analysis completed does indicate that deregulation should provide lower electricity costs for Navy organizations classified as large industrial/commercial users. The concerns addressed by the legislature and the California Public Utilities Commission (CPUC) do indicate that similar marginal savings should be realized by other customers as well.

As previously discussed, the Competitive Transition Charge (CTC) is designed to recover the costs of uneconomical assets for the investor owned utilities (IOUs). This charge equates to $459,573.72 for the Naval Postgraduate School's Main Station. If these costs are recovered as planned, significant future cost savings would be realized after the transition period ends on December 31, 2001.

In theory, deregulation should provide many opportunities for cost savings. However, many uncertainties remain to be resolved. The effects of deregulation on the electricity market will not be realized until the transition period is complete and a truly competitive generation market exists.

B. RECOMMENDATIONS

Based on the research and analysis completed, it is recommended that the base commander who receives electricity from one of the three IOUs continue to retain electricity service from that supplier. Reasons to retain their service are:

- Initial analysis indicates a possible reduction in the cost of electricity under deregulation.

- Retail customers of the IOUs are obligated to pay the Competitive Transition Charge regardless of their supplier, therefore the CTC is inescapable. [Ref. 11:Section V] For example, if NPS's Main Station chooses to contract electricity from a direct access supplier, the total cost of electricity would equal the contract price plus the CTC of approximately $400,000.

- Customers who purchase electricity from suppliers at a price greater than the Power Exchange price may incur an increase in total costs. Customers who purchase electricity from the IOUs would not incur a rate increase because the mandatory buy-sell policy discussed in Chapter III directs the IOUs to purchase their electricity from the PX. This would only apply during the transition period due to the CTC. [Ref. 10:Section 367.E.2]

- The uncertainties in key services, such as transmission and distribution, could increase costs.

- Significant cost savings could result after elimination of the Competitive Transition Charge.

On January 1, 2002, if the CPUC removes CTC and competition emerges as planned, Navy organizations should solicit bids for their electricity service.

C. RECOMMENDED AREAS FOR FUTURE STUDY

Follow-on research could be conducted in the following areas:

- Electricity rate comparison before and after deregulation.

- The cost of electricity contracted through an aggregate buy for the entire Department of the Navy and possibly the Department of Defense.

APPENDIX A - NPS ELECTRIC BILLS

Naval Postgraduate School Electric Bills

DATE		Season	Demand (kW)			Energy (kWh)			Total kWh	Days in Billing Cycle	Avg. Daily Consumption
Starting	Ending		Peak	Partial Peak	Off Peak	Peak	Partial Peak	Off Peak			
23-Sep-94	24-Oct-94	S	2,664	2,654	2,424	297,043	317,671	760,486	1,375,200	31	44,361
24-Oct-94	31-Oct-94	S	2,695	2,692	1,953	88,608	95,424	190,848	374,880	7	53,554
01-Nov-94	22-Nov-94	W	0	2,812	1,953	0	434,861	553,459	988,320	21	47,063
22-Nov-94	22-Dec-94	W	0	2,875	2,584	0	647,885	772,915	1,420,800	30	47,360
22-Dec-94	24-Jan-95	W	0	2,724	2,527	0	610,548	860,652	1,471,200	33	44,582
24-Jan-95	23-Feb-95	W	0	2,760	2,527	0	----	----	1,413,600	30	47,120
23-Feb-95	24-Mar-95	W	0	2,796	2,527	0	642,816	739,584	1,382,400	29	47,669
24-Mar-95	24-Apr-95	W	0	2,702	2,481	0	622,339	788,861	1,411,200	31	45,523
24-Apr-95	30-Apr-95	W	0	2,589	2,371	0	146,234	175,750	321,984	6	53,664
01-May-95	23-May-95	S	2,685	2,683	2,431	229,414	245,513	544,689	1,019,616	22	46,346
23-May-95	22-Jun-95	S	2,635	2,616	2,373	290,606	313,373	735,221	1,339,200	30	44,640
22-Jun-95	24-Jul-95	S	2,625	2,606	2,361	285,610	303,206	764,784	1,353,600	32	42,300
24-Jul-95	22-Aug-95	S	2,596	2,556	2,320	296,218	314,093	666,489	1,276,800	29	44,028
22-Aug-95	21-Sep-95	S	2,889	2,848	2,637	302,669	322,937	725,594	1,351,200	30	45,040
21-Sep-95	20-Oct-95	S	2,642	2,652	2,400	295,488	316,224	684,288	1,296,000	29	44,690
20-Oct-95	31-Oct-95	S	2,613	2,601	2,412	115,279	123,818	300,296	539,393	11	49,036
01-Nov-95	21-Nov-95	W	0	2,707	2,452	0	399,919	483,888	883,807	20	44,190
21-Nov-95	21-Dec-95	W	0	2,685	2,488	0	623,760	732,240	1,356,000	30	45,200
21-Dec-95	23-Jan-96	W	0	2,721	2,508	0	593,501	812,899	1,406,400	33	42,618
23-Jan-96	22-Feb-96	W	0	2,688	2,512	0	636,718	738,482	1,375,200	30	45,840
22-Feb-96	22-Mar-96	W	0	2,697	2,503	0	632,890	696,710	1,329,600	29	45,848
22-Mar-96	22-Apr-96	W	0	2,647	2,426	0	619,421	750,979	1,370,400	31	44,206
22-Apr-96	30-Apr-96	W	0	2,647	2,388	0	209,563	202,759	412,322	8	51,540
01-May-96	22-May-96	S	2,659	2,642	2,421	216,367	229,975	502,136	948,478	21	45,166
22-May-96	21-Jun-96	S	2,556	2,580	2,344	293,040	314,160	712,800	1,320,000	30	44,000
21-Jun-96	23-Jul-96	S	2,520	2,527	2,335	280,039	298,620	748,541	1,327,200	32	41,475
23-Jul-96	21-Aug-96	S	2,584	2,558	2,335	296,050	313,992	671,558	1,281,600	29	44,193
21-Aug-96	20-Sep-96	S	2,630	2,582	2,349	297,036	317,016	717,948	1,332,000	30	44,400

APPENDIX B - CLASSICAL DECOMPOSITION FORECAST

Classical Decomposition Time Series Analysis

Year	Month	Period	Y	MA	Y/MA	S	Y/S	Period	Y=T*S
1994	October	1	46,055	*	*	1.0231	45,015	Oct-94	47,614
1994	November	2	47,063	*	*	1.0065	46,759	Nov-94	46,720
1994	December	3	47,360	*	*	0.9966	47,520	Dec-94	46,142
1995	January	4	44,582	46,707	0.9545	0.9487	46,993	Jan-95	43,809
1995	February	5	47,120	46,713	1.0087	1.0049	46,890	Feb-95	46,283
1995	March	6	47,669	46,427	1.0268	1.0197	46,748	Mar-95	46,841
1995	April	7	46,843	46,010	1.0181	1.0231	45,785	Apr-95	46,874
1995	May	8	46,346	45,562	1.0172	1.0065	46,047	May-95	45,992
1995	June	9	44,640	45,085	0.9901	0.9966	44,791	Jun-95	45,421
1995	July	10	42,300	44,786	0.9445	0.9487	44,587	Jul-95	43,122
1995	August	11	44,028	44,527	0.9888	1.0049	43,813	Aug-95	45,556
1995	September	12	45,040	44,394	1.0146	1.0197	44,170	Sep-95	46,104
1995	October	13	45,885	44,467	1.0319	1.0231	44,849	Oct-95	46,134
1995	November	14	44,190	44,645	0.9898	1.0065	43,905	Nov-95	45,264
1995	December	15	45,200	44,863	1.0075	0.9966	45,353	Dec-95	44,700
1996	January	16	42,618	44,916	0.9488	0.9487	44,923	Jan-96	42,436
1996	February	17	45,840	44,983	1.0191	1.0049	45,616	Feb-96	44,829
1996	March	18	45,848	44,964	1.0197	1.0197	44,962	Mar-96	45,366
1996	April	19	45,711	44,769	1.0211	1.0231	44,679	Apr-96	45,394
1996	May	20	45,166	44,536	1.0141	1.0065	44,874	May-96	44,536
1996	June	21	44,000	44,278	0.9937	0.9966	44,149	Jun-96	43,979
1996	July	22	41,475	*	*	0.9487	43,718	Jul-96	41,750
1996	August	23	44,193	*	*	1.0049	43,978	Aug-96	44,102
1996	September	24	44,400	*	*	1.0197	43,542	Sep-96	44,629
1996	October	25	*	*	*	1.0231	*	Oct	44,654
1996	November	26	*	*	*	1.0065	*	Nov	43,808
1996	December	27	*	*	*	0.9966	*	Dec	43,258
1997	January	28	*	*	*	0.9487	*	Jan	41,064
1997	February	29	*	*	*	1.0049	*	Feb	43,375
1997	March	30	*	*	*	1.0197	*	Mar	43,891
1997	April	31	*	*	*	1.0231	*	Apr	43,914
1997	May	32	*	*	*	1.0065	*	May	43,080
1997	June	33	*	*	*	0.9966	*	Jun	42,538
1997	July	34	*	*	*	0.9487	*	Jul	40,378
1997	August	35	*	*	*	1.0049	*	Aug	42,649
1997	September	36	*	*	*	1.0197	*	Sep	43,154

Seasonal Index Calculation (S)

Period	1995	1995	1996	Mean	Adj Mean
Jan/July	0.9545	0.9445	0.9488	0.9493	0.9488
Feb/Aug	1.0087	0.9888	1.0191	1.0055	1.0050
Mar/Sep	1.0268	1.0146	1.0197	1.0203	1.0198
Apr/Oct	1.0181	1.0319	1.0211	1.0237	1.0232
May/Nov	1.0172	0.9898	1.0141	1.0071	1.0066
Jun/Dec	0.9901	1.0075	0.9937	0.9971	0.9966
Total				6.0030	6.0000

SUMMARY OUTPUT

Regr. Statistics	
Multiple R	0.735341
R Square	0.540727
Adj. R Sq.	0.51985
Std Error	803.1998
Observations	24

(T=aX+b)	Coeff.	Std Error	t Stat	P-value
Intercept	46659.58	338.4286	137.8713	8.293E-34
X Variable	-120.542	23.68507	-5.08938	4.244E-05

ANOVA

	df	SS	MS	F	Sign. F
Regression	1	18988778	18988778	27.771193	2.748E-05
Residual	22	15042678	683758.1		
Total	23	34031456			

Monthly Forecast

Period	Forecast	No. of Day	kWh
October	44,654	31	1,384,274
November	43,808	30	1,314,240
December	43,258	31	1,340,998
January	41,064	31	1,272,984
February	43,375	28	1,214,500
March	43,891	31	1,360,621
April	43,914	30	1,317,420
May	43,080	31	1,335,480
June	42,538	30	1,276,140
July	40,378	31	1,251,718
August	42,649	31	1,322,119
September	43,154	30	1,294,620

APPENDIX C - ENERGY FORECAST

Period Allocation of Consumption

Date		Energy (kWh)			Total	kWh Percent			
Starting	Ending	Peak	Partial Peak	Off Peak	Total kWh	Peak	Partial Peak Summer	Partial Peak Winter	Off Peak
23-Sep-94	24-Oct-94	297,043	317,671	760,486	1,375,200	0.2160	0.2310	0.0000	0.5530
24-Oct-94	31-Oct-94	88,608	95,424	190,848	374,880	0.2364	0.2545	0.0000	0.5091
01-Nov-94	22-Nov-94	0	434,861	553,459	988,320	0.0000	0.0000	0.4400	0.5600
22-Nov-94	22-Dec-94	0	647,885	772,915	1,420,800	0.0000	0.0000	0.4560	0.5440
22-Dec-94	24-Jan-95	0	610,548	860,652	1,471,200	0.0000	0.0000	0.4150	0.5850
24-Jan-95	23-Feb-95	0	----	----	1,413,600	0.0000	0.0000	----	----
23-Feb-95	24-Mar-95	0	642,816	739,584	1,382,400	0.0000	0.0000	0.4650	0.5350
24-Mar-95	24-Apr-95	0	622,339	788,861	1,411,200	0.0000	0.0000	0.4410	0.5590
24-Apr-95	30-Apr-95	0	146,234	175,750	321,984	0.0000	0.0000	0.4542	0.5458
01-May-95	23-May-95	229,414	245,513	544,689	1,019,616	0.2250	0.2408	0.0000	0.5342
23-May-95	22-Jun-95	290,606	313,373	735,221	1,339,200	0.2170	0.2340	0.0000	0.5490
22-Jun-95	24-Jul-95	285,610	303,206	764,784	1,353,600	0.2110	0.2240	0.0000	0.5650
24-Jul-95	22-Aug-95	296,218	314,093	666,489	1,276,800	0.2320	0.2460	0.0000	0.5220
22-Aug-95	21-Sep-95	302,669	322,937	725,594	1,351,200	0.2240	0.2390	0.0000	0.5370
21-Sep-95	20-Oct-95	295,488	316,224	684,288	1,296,000	0.2280	0.2440	0.0000	0.5280
20-Oct-95	31-Oct-95	115,279	123,818	300,296	539,393	0.2137	0.2296	0.0000	0.5567
01-Nov-95	21-Nov-95	0	399,919	483,888	883,807	0.0000	0.0000	0.4525	0.5475
21-Nov-95	21-Dec-95	0	623,760	732,240	1,356,000	0.0000	0.0000	0.4600	0.5400
21-Dec-95	23-Jan-96	0	593,501	812,899	1,406,400	0.0000	0.0000	0.4220	0.5780
23-Jan-96	22-Feb-96	0	636,718	738,482	1,375,200	0.0000	0.0000	0.4630	0.5370
22-Feb-96	22-Mar-96	0	632,890	696,710	1,329,600	0.0000	0.0000	0.4760	0.5240
22-Mar-96	22-Apr-96	0	619,421	750,979	1,370,400	0.0000	0.0000	0.4520	0.5480
22-Apr-96	30-Apr-96	0	209,563	202,759	412,322	0.0000	0.0000	0.5083	0.4917
01-May-96	22-May-96	216,367	229,975	502,136	948,478	0.2281	0.2425	0.0000	0.5294
22-May-96	21-Jun-96	293,040	314,160	712,800	1,320,000	0.2220	0.2380	0.0000	0.5400
21-Jun-96	23-Jul-96	280,039	298,620	748,541	1,327,200	0.2110	0.2250	0.0000	0.5640
23-Jul-96	21-Aug-96	296,050	313,992	671,558	1,281,600	0.2310	0.2450	0.0000	0.5240
21-Aug-97	20-Sep-97	297,036	317,016	717,948	1,332,000	0.2230	0.2380	0.0000	0.5390
Average:	Summer (S)					0.2227	0.2380	----	0.5393
	Winter (W)					----	----	0.4542	0.5458

Energy Allocation

Month	Daily kWh	Number of Days	Monthly Total	Peak 22.27%	Partial Peak 23.80% (S) 45.42% (W)	Off Peak 53.93% (S) 54.58% (W)
October	44,654	31	1,384,274	308,278	329,457	746,539
November	43,808	30	1,314,240	0	596,928	717,312
December	43,258	31	1,340,998	0	609,081	731,917
January	41,064	31	1,272,984	0	578,189	694,795
February	43,375	28	1,214,500	0	551,626	662,874
March	43,891	31	1,360,621	0	617,994	742,627
April	43,914	30	1,317,420	0	598,372	719,048
May	43,080	31	1,335,480	297,411	317,844	720,224
June	42,538	30	1,276,140	284,196	303,721	688,222
July	40,378	31	1,251,718	278,758	297,909	675,052
August	42,649	31	1,322,119	294,436	314,664	713,019
September	43,154	30	1,294,620	288,312	308,120	698,189

APPENDIX D - DEMAND FORECAST

Naval Postgraduate School Electricity Demand

Summer Demand

Month	Demand (kW) On Peak	Partial Peak	Off Peak
Oct-94	2,695	2,692	2,424
May-95	2,685	2,683	2,431
Jun-95	2,635	2,616	2,373
Jul-95	2,625	2,606	2,361
Aug-95	2,596	2,556	2,320
Sep-95	2,889	2,848	2,637
Oct-95	2,642	2,652	2,412
May-96	2,659	2,642	2,421
Jun-96	2,556	2,580	2,344
Jul-96	2,520	2,527	2,335
Aug-96	2,584	2,558	2,335
Sep-96	2,630	2,582	2,349

Summer Demand with September 1995 Removed

Month	Demand (kW) On Peak	Partial Peak	Off Peak
Oct-94	2,695	2,692	2,424
May-95	2,685	2,683	2,431
Jun-95	2,635	2,616	2,373
Jul-95	2,625	2,606	2,361
Aug-95	2,596	2,556	2,320
Oct-95	2,642	2,652	2,412
May-96	2,659	2,642	2,421
Jun-96	2,556	2,580	2,344
Jul-96	2,520	2,527	2,335
Aug-96	2,584	2,558	2,335
Sep-96	2,630	2,582	2,349

Summer Demand Forecast

Month	Peak	Partial Peak	Off Peak
Oct	2,669	2,672	2,418
May	2,672	2,663	2,426
Jun	2,596	2,598	2,359
Jul	2,573	2,567	2,348
Aug	2,590	2,557	2,328
Sep	2,630	2,582	2,349

Winter Demand

Month	Demand (kW) Partial Peak	Off Peak
Nov-94	2,812	1,953
Dec-94	2,875	2,584
Jan-95	2,724	2,527
Feb-95	2,760	2,527
Mar-95	2,796	2,527
Apr-95	2,702	2,481
Nov-95	2,707	2,452
Dec-95	2,685	2,488
Jan-96	2,721	2,508
Feb-96	2,688	2,512
Mar-96	2,697	2,503
Apr-96	2,647	2,426

Winter Demand Forecast

Month	Partial Peak	Off Peak
Nov	2,760	2,452
Dec	2,780	2,536
Jan	2,723	2,518
Feb	2,724	2,520
Mar	2,747	2,515
Apr	2,675	2,454

APPENDIX E - PG&E COST OF ELECTRICITY

PG&E Rate Schedule E-20P

Season	Demand			Energy			Customer
	On Peak	Partial Peak	Off Peak	On Peak	Partial Peak	Off Peak	Charge:
Summer	$11.80000	$2.65000	$2.55000	$0.06210	$0.04821	$0.04637	$310.00
Winter	$0.00000	$2.65000	$2.55000	$0.00000	$0.05624	$0.04719	$310.00

Month	Demand			Energy			Meters
	On Peak	Partial Peak	Off Peak	On Peak	Partial Peak	Off Peak	
October	2,669	2,672	2,418	307,278	329,457	746,539	1
November	0	2,760	2,452	0	596,928	717,312	1
December	0	2,780	2,536	0	609,081	731,917	1
January	0	2,723	2,518	0	578,189	694,795	1
February	0	2,724	2,520	0	551,626	662,874	1
March	0	2,747	2,515	0	617,994	742,627	1
April	0	2,675	2,454	0	598,372	719,048	1
May	2,672	2,663	2,418	297,411	317,844	720,224	1
June	2,596	2,598	2,426	284,196	303,721	688,222	1
July	2,573	2,567	2,359	278,758	297,909	675,052	1
August	2,590	2,557	2,328	294,436	314,664	713,019	1
September	2,630	2,582	2,349	288,312	308,120	698,189	1

Month	Demand			Demand	Energy			Energy	Customer	Monthly
	On Peak	Partial Peak	Off Peak	Total	On Peak	Partial Peak	Off Peak	Total	Charge	Total
October	$31,494.20	$7,080.80	$6,165.90	$44,740.90	$19,081.96	$15,883.12	$34,617.02	$69,582.10	$310.00	$114,633.00
November	$0.00	$7,314.00	$6,252.60	$13,566.60	$0.00	$33,571.23	$33,849.95	$67,421.18	$310.00	$81,297.78
December	$0.00	$7,367.00	$6,466.80	$13,833.80	$0.00	$34,254.72	$34,539.16	$68,793.88	$310.00	$82,937.68
January	$0.00	$7,215.95	$6,420.90	$13,636.85	$0.00	$32,517.35	$32,787.38	$65,304.73	$310.00	$79,251.58
February	$0.00	$7,218.60	$6,426.00	$13,644.60	$0.00	$31,023.45	$31,281.02	$62,304.47	$310.00	$76,259.07
March	$0.00	$7,279.55	$6,413.25	$13,692.80	$0.00	$34,755.98	$35,044.57	$69,800.55	$310.00	$83,803.35
April	$0.00	$7,088.75	$6,257.70	$13,346.45	$0.00	$33,652.44	$33,931.88	$67,584.32	$310.00	$81,240.77
May	$31,529.60	$7,056.95	$6,165.90	$44,752.45	$18,469.22	$15,323.26	$33,396.79	$67,189.27	$310.00	$112,251.72
June	$30,632.80	$6,884.70	$6,186.30	$43,703.80	$17,648.57	$14,642.39	$31,912.85	$64,203.81	$310.00	$108,217.61
July	$30,361.40	$6,802.55	$6,015.45	$43,179.40	$17,310.87	$14,362.19	$31,302.16	$63,255.22	$310.00	$106,744.62
August	$30,562.00	$6,776.05	$5,936.40	$43,274.45	$18,284.48	$15,169.95	$33,062.69	$66,517.12	$310.00	$110,101.57
September	$31,034.00	$6,842.30	$5,989.95	$43,866.25	$17,904.18	$14,854.47	$32,375.02	$65,133.67	$310.00	$109,309.92
Totals	$185,614.00	$84,927.20	$74,697.15	$345,238.35	$108,699.28	$290,010.55	$398,100.49	$796,810.32	$3,720.00	$1,145,768.67

APPENDIX F - UNBUNDLED COST OF ELECTRICITY

Pacific Gas and Electric Unbundled Costs for E-20 Rate Schedule

Category	PX Price (Gen)	Transmission	Distribution	Social/Env.	Transition	Nuclear Decom	Total
Cost per kWh	$0.0240	$0.0023	$0.0096	$0.0026	$0.0290	$0.0003	$0.0678

Unbundled Cost Estimate

		Cost of Service				Transition Cost		
Month	**Total Consumption**	**PX Price (Generation)**	**Trans.**	**Dist.**	**Social/ Environ.**	**Transition**	**Nuclear Decom**	**Total**
October	1,384,274	$33,222.58	$3,183.83	$13,289.03	$3,599.11	$40,143.95	$415.28	$93,853.78
November	1,314,240	$31,541.76	$3,022.75	$12,616.70	$3,417.02	$38,112.96	$394.27	$89,105.46
December	1,340,998	$32,183.95	$3,084.30	$12,873.58	$3,486.59	$38,888.94	$402.30	$90,919.66
January	1,272,984	$30,551.62	$2,927.86	$12,220.65	$3,309.76	$36,916.54	$381.90	$86,308.33
February	1,214,500	$29,148.00	$2,793.35	$11,659.20	$3,157.70	$35,220.50	$364.35	$82,343.10
March	1,360,621	$32,654.90	$3,129.43	$13,061.96	$3,537.61	$39,458.01	$408.19	$92,250.10
April	1,317,420	$31,618.08	$3,030.07	$12,647.23	$3,425.29	$38,205.18	$395.23	$89,321.08
May	1,335,480	$32,051.52	$3,071.60	$12,820.61	$3,472.25	$38,728.92	$400.64	$90,545.54
June	1,276,140	$30,627.36	$2,935.12	$12,250.94	$3,317.96	$37,008.06	$382.84	$86,522.28
July	1,251,718	$30,041.23	$2,878.95	$12,016.49	$3,254.47	$36,299.82	$375.52	$84,866.48
August	1,322,119	$31,730.86	$3,040.87	$12,692.34	$3,437.51	$38,341.45	$396.64	$89,639.67
September	1,294,620	$31,070.88	$2,977.63	$12,428.35	$3,366.01	$37,543.98	$388.39	$87,775.24
Subtotals		$376,442.74	$36,075.76	$150,577.08	$40,781.28	$454,868.31	$4,705.55	$1,063,450.72
Totals					**$603,876.86**		**$459,573.86**	**$1,063,450.72**

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